DISPERSION MODELING ANALYSIS OF PSD CLASS I INCREMENT CONSUMPTION IN NORTH DAKOTA AND EASTERN MONTANA

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 8 AIR AND RADIATION PROGRAM
999 18TH ST, SUITE 300
DENVER, COLORADO 80202

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1. Introduction

The provisions of the Prevention of Significant Deterioration (PSD) program were enacted by Congress in the 1977 Clean Air Act (Act). The purpose of this program is to ensure that the air quality in clean air areas does not degrade significantly. To prevent significant deterioration of air quality, Congress set up the principle of only allowing a certain amount of increase in the ambient air concentration over the existing baseline concentration. These allowable increases are known as the "PSD increments." The Clean Air Act provides for three different classes of air quality protection, to reflect varying levels of protection from significant deterioration in air quality. In the 1977 Act, Congress designated a number of "Class I areas" that are to receive special protection from degradation of air quality and, thus, the most stringent PSD increments apply in these areas.

In 1999 North Dakota conducted a draft modeling analysis that shows numerous violations of the Class I PSD increments for sulfur dioxide (SO_2) in four Class I areas. Those Class I areas include Theodore Roosevelt National Park, the Lostwood Wilderness Area, the Medicine Lakes Wilderness Area, and the Fort Peck Class I Indian Reservation. EPA and North Dakota could not reach agreement on an appropriate PSD increment modeling protocol to refine the 1999 study, and subsequently both NDDH and EPA have performed additional modeling analyses. EPA's draft modeling study was released on March 5, 2002 and EPA solicited public comments through April 29, 2002. EPA's modeling analysis generally followed EPA regulations and procedures for most of the parameters involved in the modeling. Any non-standard assumptions used by EPA generally followed those that the State has used in its 1999 analysis and are explained in detail in the draft EPA modeling report. EPA's draft analysis showed numerous violations in the four Class I areas, and the results were very similar to what the State showed in their original 1999 Calpuff analysis.

The State's most recent draft modeling analysis became available on the Department's web site on April 5, 2002.[1] The State's April 2002 study does not show PSD Class 1 increment violations, however, the analysis was based on a number of alternative methodologies that conflict with the methodologies outlined in the Federal PSD program and EPA's modeling requirements. As a result, it appears that the State's modeling effort is deficient and should not be used to determine whether the PSD Class I increments are being protected in the modeling domain. EPA provided extensive comments on the State's modeling study on May 24, 2002 and continues to stand behind those comments.[2]

In issuing this May 2003 version of the report, EPA has considered public comments that we received on all aspects of the draft modeling study. The analysis represents what EPA believes to

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[1]Draft North Dakota Department of Health, Division of Air Quality, Calpuff Analysis of Current PSD Class I Increment Consumption in North Dakota and Eastern Montana Using Actual Annual Average SO_2 Emission Rates (April 2002); (*available at* http://www.health.state.nd.us/psd/).

[2]EPA Comments on North Dakota Department of Health's Proposed Determination Regarding the Adequacy of the SIP to Protect PSD Increments for Sulfur Dioxide, U.S. Environmental Protection Agency, May 24, 2002.

be the most appropriate methodology to assess the status of Class 1 increment consumption in North Dakota and eastern Montana following EPA guidance and regulatory requirements.

2. Application of Calpuff Modeling System

Consistent with current Interagency Workgroup for Air Quality Modeling (IWAQM) guidance[3] EPA Region 8 decided to select the Calpuff long-range modeling system as the preferred model to evaluate air quality impacts in this analysis. Calpuff was promulgated nationally by EPA (68 FR 18439 (April 15, 2003)) as a refined modeling technique for evaluating impacts from the long- range transport of pollutants. The MESOPUFFII model is currently listed in the Guideline on Air Quality Models[4] for use on a case-by-case basis in evaluating long-range transport. MESOPUFFII is considered obsolete and has not been proposed as either a preferred or an alternative model in the proposed revisions to the modeling guideline. For this modeling study data were obtained from 25 surface meteorological stations, six upper-air stations, and 96 precipitation stations located within and near the Calpuff modeling area. The spacing of these stations provided good spatial representation over the modeling domain. The modeling area, shown in Figure 2-1, covers most of North Dakota, eastern Montana, and small portions of South Dakota, and Southern Saskatchewan. The model was applied individually for each of five years of meteorological data (1990-1994) in accordance with EPA's longstanding Guideline on Air Quality Models (Guideline). This period of record is the most recent that observer-based cloud observations are available. The observer-based data may provide superior cloud cover information for modeling purposes compared to the automated data collected in subsequent years. To enhance characterization of wind fields, MM-4/MM-5 mesoscale meteorological data were incorporated into the modeling when available (1990, 1992, and 1994). Emission inputs were based on the most recent two years (2000-2001) of source data and, where available, continuous emissions monitoring system (CEMS) data were used to determine appropriate emission rates for use in the modeling. The approach EPA used in characterizing emissions is discussed in Chapter 3.

2.1 Overview of Modeling Changes in Response to Comments on Draft Report

2.1.1 Background Concentrations

To determine the effectiveness of selected Calpuff control file settings, as well as the utility of the Calmet/Calpuff implementation in general, NDDH conducted a limited model performance evaluation, using data from two monitoring sites located in or near Theodore Roosevelt National Park. The NDDH Calpuff evaluation is described in the NDDH 1999 Calpuff Class I Modeling

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[3] EPA, 1998 Interagency Workgroup on Air Quality Modeling, Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts. Publication No. EPA-454/R-98-019, OAQPS, Research Triangle Park NC 27711.

[4] EPA 2003, Guideline on Air Quality Models. Code of Federal Regulations, 40 CFR part 51, Appendix W.

Figure 2-1. Key to Source Locations

1. Coal Creek Station
2. Antelope Valley Station, Great Plains Synfuels Plant
3. Coyote Station
4. Leland Olds Station, Stanton Station
5. Milton R Young Station
6. Heskett Station, Mandan Refinery
7. Little Knife Gas Plant
8. Grasslands Gas Plant
9. Tioga Gas Plant
10. Lignite Gas Plant
11. Colstrip Station
12. CELP Boiler

MLWA	Medicine Lakes Wilderness Area
TRNP-N	Theodore Roosevelt National Park- North Unit
TRNP-S	Theodore Roosevelt National Park- South Unit
LWA	Lostwood Wilderness Area

Study. NDDH has continued to test Calpuff performance using year 2000 emissions and meteorology data.[5] The evaluation of Calpuff performance for Year 2000 data at Dunn Center and TRNP South Unit monitoring sites still indicates the modeling system performs relatively well, when implemented using IWAQM control file settings as modified by NDDH. In these results predicted-to-observed ratios (unpaired in time) for the fifty highest predicted/observed concentrations fell within the factor-of-two criteria suggested by EPA's Guideline, and did not exhibit a strong systematic bias toward underprediction or overprediction.

In the public comments on EPA's draft report, several industry consultants suggested that a background concentration should have been added to the modeled component in the Calpuff performance evaluation. A background value of 4 ug/m3 was suggested, and with this addition the consultants concluded that the model was overpredicting.

In conducting the performance tests, NDDH included all significant SO_2 emission sources within 250 km of the Class 1 sites including several large sources in Canada. Oil and gas production sources (i.e., treaters and flares) were also included, but because of their greater number and smaller size, the modeled inventory of oil and gas sources was limited to those located within 50 km of each monitoring site, consistent with approach used in NDDH's modeling studies. Since these sources were already accounted for in the performance testing, the issue is what residual background concentration would remain at TRNP-South unit if these sources emitted no sulfur dioxide. The 4ug/m3 (1.5 ppb) concentration suggested by industry consultants is nearly double the annual average of 2.1 ug/m3 observed at the TRNP-South Unit monitoring site in 2000, even when these sources are impacting monitored values, thus a background value of this magnitude is clearly not credible.

The residence time of SO2 in the atmosphere is limited because SO2 is oxidized to particulate sulfate and is removed through deposition and other mechanisms. For this reason monitored concentrations from very distant emissions sources of SO2 are likely negligible. Published global background SO2 concentrations for a remote location range between 0.02 and 0.2 ppb.[6] EPA identified a regional site that is located away from the area of interest but is impacted by similar natural and distant man-made sources. A 1995 SO2 monitoring study was conducted in a relatively remote location at Juniper Mountain, near Craig, Colorado[7]. The monitor was a high sensitivity instrument with a threshold as low as .02 ppb. Despite several large SO2 emission sources within 50 miles of the monitor, the long term average concentration at Juniper Mountain

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[5] NDDH Draft Report, Evaluation of Calpuff Model Performance Using Year 2000 Data, November 2001

[6]Charlson, Global Biogeochemical Cycles, Academic Press Inc, Harcourt Brace Jovanovich Publishers, 1992

[7]Mt. Zirkel Wilderness Area Reasonable Attribution Study of Visibility Impairment, Final Report, Desert Research Institute, July 1996

was .17 ppb which is close to the upper range of Charlson's published background value. EPA believes that a background value of 0.2 ppb is appropriate for TRNP-South Unit. This value when added to predicted concentrations in the NDDH performance tests would have no effect on the overall conclusions that the model was performing well within EPA's critera with no systematic bias toward either underprediction or overprediction.

Other commentors believed that a background concentration should be added to modeled values in the PSD increment modeling. This would be feasible only if reliable background SO2 monitoring data were available in both the baseyear and current year. Since this is not the case, the same background concentration is assumed for both the baseline and current modeled inventories, thus the background values cancel out in the net result.

2.1.2 Denser Receptor Grid

One commentor recommended a 2 by 2 kilometer receptor network be used in the Class 1 areas to ensure that maximum SO2 concentrations are determined. In the EPA draft modeling study receptors were placed in the Class 1 areas at approximately 5 kilometer intervals. In response EPA has increased the number of receptors from 49 in the draft study to114 in the current study, which approximates 2 km spacing in the North Dakota Class 1 areas. A detailed description of the receptor locations is provided in section 2.3

2.1.3 Additional Model Testing

MM-4/MM-5 Enhancements

Several industry commentors stated that the upper air meteorological data relied on by NDDH and EPA for Calmet modeling were inferior to using MM-5 data in predicting plume behavior. To test this theory, EPA obtained MM-4 and MM-5 data for three years (1990, 1992 and 1994) covering the North Dakota modeling domain. These three years were selected because they represent the most recent, readily available meteorological data sets for which observer-based surface meteorological observations are available. The 1990 and 1992 data has been processed on an 80 km grid and this resolution provides upper air data in the region between the power plants and the Class 1 areas as shown in Figure 2-2. EPA then reran the 1990 and 1992 Calpuff/Calmet simulations contained in our January 2002 draft report with the MM-4/5 data incorporated. A comparison between the original results and the results with MM-4/5 is shown in Tables 2-1 and 2-2. From the tables it is evident that there was very little change in overall concentrations between the two results. The locations of maximum concentrations have moved around somewhat, there are slightly fewer days of violations, and 24-hour design concentrations have increased slightly, but the overall change was insignificant.

Table 2-1.
Comparison of 1992 Calpuff predictions, with (bold) and without MM-5 analysis.

	Theodore Roosevelt National Park, South Unit	*Theodore Roosevelt National Park, North Unit*	*Theodore Roosevelt National Park, Elkhorn Unit*	*Lostwood Wilderness Area*
3-hr Predictions 2nd High # Violations	**25** / <25 µg/m^3 **0**/ 0	**26.9**/ 27.7 µg/m^3 **1**/ 2	**<25**/ <25 µg/m^3 **0**/ 0	**<25**/ <25 µg/m^3 **0**/ 0
24-hr Predictions 2nd High # Violations	**<5** / 5.4 µg/m^3 **0**/ 1	**7.9**/ 7.0 µg/m^3 **4**/ 5	**8.6** / <5 µg/m^3 **1**/ 0	**5.8**/ 7.7 µg/m^3 **5**/ 7

	Medicine Lakes Wilderness Area	*Fort Peck Indian Reservation*	EPA's Class I SO2 Increments
3-hr Predictions 2nd High # Violations	**<25** / <25 µg/m^3 **0**/ 0	**<25**/ <25 µg/m^3 **0**/ 0	25 µg/m^3
24-hr Predictions 2nd High # Violations	**6.0**/ 5.6 µg/m^3 **3**/ 1	**8.0**/ 5.5 µg/m^3 **4**/ 1	5 µg/m^3

Table 2-2.
Comparison of 1990 Calpuff predictions, with (bold) and without MM-5 analysis

	Theodore Roosevelt National Park, South Unit	*Theodore Roosevelt National Park, North Unit*	*Theodore Roosevelt National Park, Elkhorn Unit*	*Lostwood Wilderness Area*
3-hr Predictions 2nd High # Violations	**36.4**/ 31.4 µg/m^3 **3**/ 3	**23.5**/ 29.0 µg/m^3 **0**/ 1	**<25**/ <25 µg/m^3 **0**/ 0	**<25**/ <25 µg/m^3 **0**/ 0
24-hr Predictions 2nd High # Violations	**13.4**/ 12.8 µg/m^3 **6**/ 7	**10.3**/ 10.5 µg/m^3 **3**/ 8	**6.0**/ 6.9 µg/m^3 **1**/ 4	**5.6**/ 6.6 µg/m^3 **3**/ 6

	Medicine Lakes Wilderness Area	*Fort Peck Indian Reservation*	EPA's Class I SO2 Increments
3-hr Predictions 2nd High # Violations	**<25**/ 25.9 µg/m^3 **0**/ 1	**<25**/ <25 µg/m^3 **0**/ 0	25 µg/m^3
24-hr Predictions 2nd High # Violations	**<5**/< 5 µg/m^3 **0**/ 0	**<5**/ 6.2 µg/m^3 **0**/ 1	5 µg/m^3

EPA funded a contractor to perform the 1994 MM5 modeling for the current study domain. The MM5 model was applied using an enhanced 20 km horizontal resolution and 35 vertical layers.

The meteorology predictions from the MM5 model were compared with actual weather observations during1994. The performance of the MM5 predictions was evaluated and compared with the performance of historical MM5 applications that have been accepted for use in regulatory applications elsewhere throughout the United States. The 1994 MM5 application was shown to perform with approximately the same skill level as demonstrated in these previous regulatory applications. A report describing the 1994 MM5 modeling is available on request from EPA Region 8[8]. EPA then performed Calmet/Calpuff modeling using 1994 meteorology data, and the emissions scenarios from the current study, both with and without the enhanced MM5 data. A comparison showing the effect on 1994 predicted concentrations of MM5 is shown in Table 2-3. From the table it can be seen that receptor locations at Elkhorn Ranch and further north generally have lower concentrations when MM5 is incorporated into the modeling. However, concentrations in TRNP- South Unit were the same or slightly higher when MM5 is incorporated. The results show that the 1994 design concentration for establishing emission control requirements would increase from 7.8 ug/m3 without MM5 to 9.3 ug/m3 when MM5 is used.

Table 2-3. Comparison of 1994 Calpuff predictions, with (bold) and without MM-5 analysis

	Theodore Roosevelt National Park, South Unit	*Theodore Roosevelt National Park, North Unit*	*Theodore Roosevelt National Park, Elkhorn Unit*	*Lostwood Wilderness Area*
3-hr Predictions 2nd High # Violations	**23.6**/ 22.3 **0**/ 0	**18.1**/ 24.2 **0**/ 0	**16.3**/ 20.1 **0**/ 0	**20.4**/ 24.0 **0**/ 0
24-hr Predictions 2nd High # Violations	**9.3**/ 7.8 **7**/ 4	**5.5**/ 6.8 **1**/ 8	**2.8**/ 2.4 **0**/ 0	**5.4**/ 8.0 **2**/ 11

	*Medicine Lakes Wilderness Area**	*Fort Peck Indian Reservation**	EPA's Class I SO2 Increments
3-hr Predictions 2nd High # Violations	**9.2**/ 17.0 **0**/ 0	**15.7**/ 15.6 **0** /0	25 µg/m^3
24-hr Predictions 2nd High # Violations	**3.2**/ 5.4 **0**/ 1	**4.4**/ 6.0 **0**/ 2	5 µg/m^3

* Modeled values using North Dakota baseline date emissions inventory

The relatively small differences between the three results may be attributable to the fact that the original data set is quite robust (e.g., 25 surface weather stations, 96 precipitation stations, and 6 upper air stations) and the MM-4/5 developed wind information was very similar to that

[8] D. McNally, T. Tesche, Annual Application of MM5 to Support Calpuff Air Quality Modeling, December 2002, Alpine Geophysics, LLC Arvada, CO.

developed using measured observations in the original model. The relatively flat terrain features also likely contributed to similar results. Although the addition of MM-4 and MM-5 have not significantly changed the results, EPA has included these data in the current analyses for those years in which it was available (1990, 1992, and 1994). There is little effect on model execution time when these data are incorporated.

Enhanced Vertical and Horizontal Resolution:

A number of commentors at the May 2002 Public Hearing in Bismarck stated that they believed the horizontal and vertical resolution that EPA and NDDH used in both studies was inadequate to characterize meteorological conditions affecting plume transport and dispersion. To determine the effect on model predictions, NDDH conducted a number of model tests to determine the sensitivity of Calpuff predictions to changes in the grid configuration[9]. Testing was conducted for grid cell sizes of 10 km, 5 km and 3 km, and for 8 vs.12 vertical layers. The following four grid configurations were evaluated in the testing:

1) 10 x 8 (10 km grid cell size and 8 vertical layers)
2) 5 x 8 (5 km grid cell size and 8 vertical layers)
3) 5 x 12 (5 km grid cell size and 12 vertical layers)
4) 3 x 12 (3 km grid cell size and 12 vertical layers)

The 10 x 8 grid reflects the configuration utilized by both NDDH and EPA in their draft studies while the 3 x 12 grid is consistent with a proposal from an industry consultant. To simplify the testing process, NDDH only tested large, increment-consuming sources only (i.e., oil and gas were not modeled). Thus, these modeled "sensitivity test" results are useful in a relative sense, but do not reflect true increment consumption.

NDDH used year 2000 meteorological data in the sensitivity testing which did not include MM4/MM5 data. Calpuff/Calmet technical settings were similar to those previously used and documented by NDDH and EPA. Layer-dependent bias (surface vs. upper air) for 12 layer tests was parameterized as closely as possible to settings for 8 layer tests. Receptor locations were equivalent to Class I area receptors previously used by NDDH and EPA.

Results of the sensitivity study are provided in Table 2-4. High, second-high predictions are provided for each grid configuration. Sensitivity results indicate very little difference in predictions for the four configurations tested.

[9] Memorandum from Steven F. Weber, Manager, Air Quality Impact, NDDH Air Quality Division to Interested Parties (September 26,2002).(available at: http: //www.epa.gov/region08/air/ndair.html)

Table 2-4. Calpuff/Calmet Sensitivity Testing -Variation in Calpuff Predicted High-Second High (HSH) Concentrations ($\mu g/m^3$) Using Various Vertical and Horizontal Grid Configurations

	T.R. South	T.R. North	T.R. Elkhorn	Lostwood	Overall
3-hr HSH					
10 x 8 grid*	18.3	16.7	22.4	22.4	22.4
5 x 8 grid*	18.7	17.4	22.3	23.1	23.1
5 x 12 grid*	19.1	15.4	22.5	21.1	22.5
3 x 12 grid*	19.4	15.7	22.7	22.0	22.7
24-hr HSH					
10 x 8 grid*	6.1	5.3	5.9	5.1	6.1
5 x 8 grid*	6.2	5.3	6.0	5.1	6.2
5 x 12 grid*	6.5	5.4	6.2	5.2	6.5
3 x 12 grid*	6.5	5.7	6.1	5.3	6.5

* The first number represents grid cell size and the second number is number of vertical layers. For example, the 10 x 8 grid uses grid cell size of 10 km and 8 vertical layers.

EPA and the U.S. Fish and Wildlife Service have also tested the effect that a 5 kilometer horizontal grid would have on model predictions using 1990 through 1994 meteorology. In these tests the model input files were identical to those used in the EPA draft report, and included both increment expanding and increment consuming sources. These tests also showed very little difference in predictions between the 10 km and 5 km configurations.

There is a significant penalty in model execution time and computer disk storage requirements when vertical and horizontal resolution are increased in Calpuff/Calmet. Since the modeling results are not significantly affected by increasing resolution beyond the original EPA settings, EPA has retained the 10 kilometer horizontal grid size and 8 vertical layers in the current analysis.

Consideration of 3-Hour Average Emissions:

One commentor to the draft EPA study noted that the use of 24-hour average emission rates in the modeling do not necessarily protect against violations of the 3-hour PSD increment. Three-hour average emission rates at a given facility are normally larger than corresponding 24-hour average rates, and therefore, EPA's use of 24-hour rates would tend to underestimate 3-hour average increment concentrations. In concept EPA agrees that 3-hour average emissions should be used in modeling the 3-hour PSD increments. However in this instance EPA believes that a State Implementation Plan that achieves compliance with the 24-hour increment would be more than sufficient to protect the 3-hour increments, and thus the additional analysis efforts to explicitly model 3-hour emission rates is unnecessary. This can be seen by reviewing the Calpuff modeling results in Tables 4-1 through 4-2. The tables show that maximum 24-hour increment concentrations are more than two times the allowable increment level of 5 ug/m3, while the 3-hour results are about 20 percent over the increment level of 25. Three-hour average emissions from the major increment consuming sources would need to be about 70 percent higher than 24-hour emission rates for the 3-hour increment to be limiting. A review of the CEM emissions data

for the largest power plants shows that peak 3-hour rates are less than 70 percent higher than the 24-hour rates used in EPA's modeling.

Consideration of Alternative Meteorological Modeling Approaches

During the May 2002 public hearing, an industry commentor presented a Calpuff analysis with year 2000 MM5 data using the National Weather Service's enhanced Rapid Uptake Cycle (RUC) data acquisition system. The analysis showed that the PSD Class 1 increments for SO2 were not threatened in any of the North Dakota or Montana Class 1 areas. EPA obtained a copy of the consultant's modeling files and reviewed the analysis. EPA's review indicated a number of serious flaws in the analysis, and we believe that the results are not credible. Some of the major problems with the modeling include:

1) The input data sets contained a number of serious technical errors including a large lake (70 by 50 km) in the modeling domain where none exists, the failure to input appropriate cloud cover data to the model during 2000, and an error in input coordinates (location) for a number of sources in the northern part of the modeling domain. These errors could significantly affect atmospheric dispersion rates and/or predicted concentrations.

2) The emission inventory used in the modeling fails to include the current year emissions of a number of large sources including: Heskett Station, Mandan refinery, and Lignite and Tioga Gas plants. Since these sources were included as baseline sources in the consultant's modeling, net increment consumption would be understated.

3)Calmet technical input options used by the consultant were not consistent with IWAQM recommendations for a number of critical parameters including use of the O'Brien procedure, number of smoothing passes (NSMTH), etc.

4) Only a single year of meteorological data was used (2000) which is not consistent with the Guideline which requires five years of data (or as few as three years if acceptable mesoscale meteorological fields are available).

5) From the Calpuff/Calmet input files it appears that MM5 data was used to replace all of the actual measured surface and upper air weather observations. This practice is not recommended by either IWAQM or the Calpuff model developer[10]. MM5 as currently configured tends to overestimate wind speeds, particularly in the lower levels of the atmosphere, unless restrained by actual observations. A comparison of the wind speeds used in the consultants modeling with those that were actually observed at the time showed that the modeled wind speeds were consistently higher than measured values. This overestimate of wind speeds was particularly apparent during stagnant conditions when predicted concentrations would be expected to occur. The consultant's use of inaccurate wind speeds in Calpuff likely resulted in increased dilution in the model and lower predicted concentrations in the Class 1 areas.

2.2 Meteorological Data Processing With Calmet

2.2.1 Input Data

The meteorological data sets used in the Calmet modeling were originally prepared by NDDH for their 1999 Draft Modeling Study[10]. In accordance with our Guidelines, EPA performed quality assurance on these data and determined that the data were adequate for use in dispersion modeling. Five years of consecutive meteorological data (1990 to 1994) were used consistent with the requirements of the EPA Guideline on Air Quality Modeling. In addition, 3 years of MM5 meteorological fields were employed in the analysis, consistent with the 2003 Guideline which encourages use of these data. Meteorological data was derived from National Weather Service, Federal Aviation Administration, U.S., and Environment Canada observations. EPA has used its expertise and judgement, as described below, and also made several changes to the Calmet IWAQM default settings based on NDDH model evaluation results and comments received on the EPA draft study. These changes are discussed below.

The Calmet software (Version 5.2) for this study was obtained from the EPA TTN-SCRAM website (http://www.epa.gov/ttn). The Fortran code was recompiled with the Portland Group compiler to facilitate faster execution time and increase Calmet's capacity to process larger files.

In establishing the size of the modeling domain, the primary goal was to provide a modeling domain which would encompass new or existing emission sources located up to 250 km from any North Dakota Class I area. The domain extends into eastern Montana, and given the relatively sparse distribution of increment consuming sources in that area, provides sufficient coverage for two eastern Montana Class I areas. The dimensions of the modeling grid are 640 km east-west and 460 km north-south. The extent of EPA's Calmet grid is illustrated in Figure 2-1.

EPA selected a 10 km grid size for this application, compared to the 20 km spacing originally used by NDDH. While a very dense grid is desirable from a scientific standpoint, computer disk storage and model execution time requirements place practical limits on grid cell size. At the 10 km resolution, a single year of Calmet-processed meteorological data requires about 2.2 gigabytes of disk space. Given the gently rolling nature of terrain, relatively uniform land-use characteristics, and the general lack of large terrain features or water bodies large enough to cause persistent, strong local-scale flows, EPA believes a 10 km grid size is adequate for this study. This is supported by the model testing discussed above which showed little difference in predictions between 3, 5, and 10 km resolutions.

In the vertical, both the EPA and the NDDH Calmet grid is defined by eight vertical layers. Cell face heights are set at 22, 50, 100, 250, 500, 1000, 2000, and 4000 meters above ground level (AGL). IWAQM does not provide specific recommendations on cell face heights, however, eight

[10] Calpuff Class 1 Area Analysis for Milton R Young Generating Station, North Dakota Dept of Health, May 24, 1999

layers is consistent with the IWAQM recommendation of 6 to 10 vertical layers, and is consistent with some of the examples and guidance provided by the model developer in documentation for the Calpuff modeling system.

NDDH obtained surface meteorological data for the five-year period 1990-1994 in TD-1440 format from the National Climatic Data Center (NCDC). Data were obtained for 25 stations (National Weather Service, Federal Aviation Administration, U.S. Military, Environment Canada) located within or near the NDDH Calmet grid. EPA has used these same data sets in the current study, including modifications made to the data sets by NDDH described below.

In the processing of the above data, NDDH's 1999 efforts found that some adjustments to the surface data files were required before Earth Tech programs METSCAN and SMERGE could be applied. Stations other than first-order National Weather Service (NWS) stations were missing opaque cloud cover for the entire five-year period. Based on a comparison of total and opaque cloud cover in the first-order NWS data sets, the NDDH developed an objective scheme to extrapolate opaque from total cloud cover. This scheme was coded into a computer program (TOT2OPQ) and applied to all surface data sets with missing opaque cloud cover.

In the 1999 study, NDDH followed EPA recommendations in data editing to account for missing data (ceiling height, wind, pressure, temperature, relative humidity). Substitutions were made if data elements were missing for one or two consecutive hours. Except for opaque cloud cover, substitutions were not made for longer missing periods (Calmet ignores stations with missing data). NDDH coded the EPA substitution scheme into a computer program (SUB144) and applied it to all surface data sets. Earth Tech's (the model developer) program METSCAN was next applied to scan each data set for missing or unreasonable values, and appropriate edits were made. Earth Tech's program SMERGE was applied to merge individual station data sets into a single input file (SURF.DAT) compatible with Calmet.

NDDH obtained upper-air meteorological data for 1990 through 1994 from the National Climatic Data Center, and precipitation data was obtained from Earth Info, Inc (Boulder, CO). Data were obtained for six upper-air stations and 96 precipitation sites located within or near the modeling domain. EPA used the same upper air and precipitation data files in the current study as NDDH employed in their original study. NDDH's data processing procedures for both the upper-air and precipitation data are discussed in their 1999 report.

Most of the terrain elevation and land use data required by Calmet were originally downloaded by NDDH from the United States Geological Survey (USGS) internet web site. Grid cell terrain elevations were derived from 1:250,000-Scale Digital Elevation Models (DEM) and land use data were derived from 1:250,000-Scale Land Use and Land Cover (LULC). The geophysical file was generated based on Calmet default land use parameters, and the State's original 20 km gridding was reprocessed for this study to a 10 km grid to be consistent with the computational grid. Because of the relatively large modeling domain, the grid system, meteorological data, and geophysical data were fit to Lambert conformal mapping to account for the earth's curvature.

2.2.3 Calmet Model Control Settings

Calmet was executed with surface data, upper-air data, precipitation data, and geophysical data as described previously, and with control file options/parameters generally established by published IWAQM guidance. As noted earlier, alternative settings were used in some cases where local testing of the model indicated an alternative setting is more appropriate. A listing of the most significant control file settings used by EPA are summarized in Table 2.-5, and a listing of non-IWAQM settings used by EPA are shown in Table 2-6. The complete EPA Calmet input control file is available in electronic format from EPA Region 8.

Table 2-5
Calmet Control File

Parameter/Option	Value
No. surface stations	24
No. upper-air stations	6
No. precip stations	96
No. X grid cells	64
No. Y grid cells	46
No. vertical layers	8
Diagnostic wind module	Yes
Use O'Brien procedure	No
Extrapolate surface wind observations	-4
RMAX1	30 km
RMAX2	40 km
TERRAD	40 km
R1	1 km
R2	10 km
No. barriers (NBAR)	0
MNMDAV	8
ILEVZI	4
Minimum overland mixing height	50 m
Maximum overland mixing height	4000 m
TRADKM	500 km
SIGMAP	100 km

Table 2-6
Non-IWAQM Settings used by EPA in Calmet Control File

Parameter	IWAQM	Current EPA Study
BIAS (Values for each vertical level)	0,0,0,0, 0,0,0,0	-1.0, -0.9, -0.7, 0.0 0.5, 1.0, 1.0, 1.0* (* 1991, 1993 only)
MNDAV	1	8
ILEVZI	1	4
ZIMAX & ZMAXW(over water)	3000 m	4000 m

The reason EPA selected each non-IWAQM setting in the current study is discussed below:

BIAS(NZ) - The IWAQM recommendation provides neutral bias (between surface and upper-air data) for all vertical layers. For the years 1990, 1992, and 1994 when enhanced MM5 upper air information was available, the IWAQM defaults were used. For the other two years (1991 and 1993), the vertical bias settings were set to minimize the effect of surface observations on far upper layer wind fields and to promote a realistic transition from surface to upper layers.

MNMDAV/ILEVZI - NDDH found that IWAQM default values for these parameters, relating to spatial averaging of mixing heights, produced unrealistic spatial variations in the mixing height field. Severe gradients (bull's eyes) in mixing height were observed in the immediate vicinity of meteorological stations, and the selected values in these input parameters smoothed the gradients. The overall area-wide average value of mixing height was not significantly affected by this change.

ZIMAX/ZIMAXW - In the western part of the upper Great Plains maximum summertime mixing heights frequently exceed the default value of 3000 m. A value of 4000 m was selected based on reported maximum mixing heights for this region (Holzworth, 1972)[11].

2.3 Calpuff Application and Postprocessing

2.3.1 Receptor Locations

A total of 114 receptor locations were selected for calculating SO2 concentrations in the 4 Class 1 Areas in North Dakota and Montana. Receptor coverage for Medicine Lake and Fort Peck Class 1

[11] Holzworth, 1972, Mixing Heights, Wind Speeds, and Potential for Urban Air Pollution Throughout the Contiguous United States, EPA, Office of Air Programs Publication AP-101

areas was less dense because they are located further from large contributing sources and therefore concentration gradients are likely to be small. Additional receptors have the disadvantage of slowing Calpuff execution times. The receptor numbers correspond to receptor locations in the following Class 1 areas.

Receptors 1-60 = TRNP South Unit
Receptors 61-95 = TRNP North Unit
Receptor 96 = TRNP Elkhorn Ranch
Receptors 97-109 = Lostwood NWA
Receptor 110 = Medicine Lake NWA
Receptors 111-114 = Fort Peck Reservation

2.3.2 Calpuff Evaluation and Model Control Settings

Calpuff was evaluated extensively prior to promulgation. To determine the effectiveness of selected Calpuff control file settings in this analysis, as well as the utility of the Calmet/Calpuff implementation in general, NDDH conducted a limited model performance evaluation, using data from two monitoring sites located in or near Theodore Roosevelt National Park. It is important to note that, compared to other long-range transport applications in the western United States, the application of Calpuff in this analysis is relatively straightforward given the gently rolling nature of terrain, relatively uniform land-use characteristics, and the general lack of large terrain features or water bodies large enough to cause persistent, strong local-scale flows. The NDDH Calpuff evaluation is described in the NDDH 1999 Calpuff Class I Modeling Study. Calpuff was tested in the NDDH study using Calmet meteorological data files prepared as described in Section 2. In general IWAQM default values were used in selecting Calpuff control file settings when other information was not available. Testing was conducted primarily to determine sensitivity of results and execution time associated with parameters/options for which default values were not provided. The goal was to achieve a technically competent implementation of the model while maintaining reasonable execution time. Calpost was applied to summarize Calpuff hourly output. Values for selected Calpuff control file parameters/options were individually and systematically varied to determine effect on results and execution time. NDDH conducted testing, for example, to determine sensitivity of results to deployment of puff splitting, terrain effects, PDF (Probability Distribution Function) for convective conditions, and partial plume penetration of elevated inversion. All seemed to have some effect on model results but, with the exception of puff splitting, none of these options caused a significant execution time penalty. Therefore, as in North Dakota's 1999 analysis, EPA has concluded it is appropriate to deploy all of these options for modeling major sources. Given the number of minor sources (principally oil and gas sources) along with execution time considerations, puff splitting was not deployed for minor sources.

NDDH has continued to test Calpuff performance using year 2000 emissions and meteorology data.[12] The evaluation was again limited by lack of representative monitoring sites so that a full

[12] NDDH Draft Report, Evaluation of Calpuff Model Performance Using Year 2000 Data, November 2001

evaluation using American Meteorological Society performance statistics could not be generated. However, the limited evaluation of Calpuff performance for Year 2000 data at Dunn Center and TRNP South Unit monitoring sites still indicates the modeling system performs relatively well, when implemented using IWAQM control file settings as modified by NDDH. In these latest results, shown in Figure 2-3, predicted-to-observed ratios (unpaired in time) for the fifty highest predicted/observed concentrations fell within the factor-of-two criteria suggested by EPA's Guideline, and did not exhibit a strong systematic bias toward underprediction or overprediction. EPA notes, however, that the 24-hour averages at TRNP South Unit are underpredicting concentrations, particularly for rankings lower than the top ten values. For increment consumption modeling, the limiting concentrations (i.e., the highest second-high predicted concentration for each year modeled) would not necessarily occur under conditions that lead to the top 10 ranked values shown in the figure. This is due to the fact that increment analysis involves modeling a limited number of emitting sources in the region, while NDDH's performance testing of the model necessarily involved modeling all major sources in the region.

EPA has reviewed the NDDH testing and evaluation results along with the latest IWAQM guidance and selected the Calpuff control file settings summarized in Table 2-7. Non-IWAQM settings are shown in Table 2-8 and the reasons for their selection are discussed below. In the current analysis EPA has generally used the same NDDH model settings as were used in the Draft 2000 model evaluation study discussed above. The changes that have been made to Calpuff inputs, such as use of MM5, have been tested by EPA and do not significantly change predictions compared to the NDDH settings used in model testing. A test run using regulatory default model settings has also been done and these results are shown in Table 4-7. From the table it can be seen that the use of IWAQM defaults increases predicted concentrations for both 3-hour and 24-hour averages. For the highest concentration receptors in TRNP, annual average concentrations were nearly 66 percent higher for the IWAQM case. Had the IWAQM defaults been used in the State's limited performance evaluation, it appears that model performance would have been degraded, with the model exhibiting a bias toward overprediction. Based on these performance results EPA has determined that the use of non-IWAQM model settings shown in Tables 2-6 and 2-8 are appropriate for the current study.

Table 2-7 Calpuff Control File

Parameter/Option	Value
No. chemical species	5
Vertical distribution near field	1
Terrain adjustment method	3
Subgrid-scale complex terrain	0
Slug model	No
Transitional plume rise	Yes

Parameter/Option	Value
Stack tip downwash	Yes
Vertical wind shear	No
Puff splitting	Yes
Chemical mechanism	1
Wet removal	Yes
Dry deposition	Yes
Dispersion coefficient method	2
Partial plume penetration - elev. inversion	Yes
PDF used under convective conditions	Yes
CSPEC	SO_2, SO_4, NO_x, HNO_3, NO_3
Chemical parameters - dry gas deposition	Default
Size parameters - dry particle deposition	Default
RCUTR	30.
RGR	10.
REACTR	8.
NINT	9
IVEG	2
Wet deposition parameters	Default
Ozone data input option	1
Background ammonia conc. (ppb)	2.
SYTDEP	550.
MHFTSZ	0
JSUP	5
XSAMLEN	0.5
MXNEW	99
MXSAM	99
Maximum mixing height (m)	4000.

Parameter/Option	Value
Minimum mixing height (m)	50.
NSPLIT	3
IRESPLIT	Hour 17 = 1
ZISPLIT (m)	100.
ROLOMAX	0.25

Table 2-8
Non-IWAQM Settings Used by EPA in Calpuff Control File

Parameter	IWAQM	EPA
MSPLIT	0	1
MDISP	3	2
BCKO3	80 ppb	30 ppb
BCKNH3	10 ppb	2 ppb
XSAMLEN	1.0	0.5
XMAXZI	3000 m	4000 m
MPDF	0	1

MSPLIT - The option for puff splitting is employed when modeling source-receptor distances of 200 km or more, because of the tendency for Calpuff to otherwise overpredict at these distances. Deployment of this option also provided better agreement with observations. Puff splitting was not used in modeling oil and gas sources.

MDISP - Use of dispersion coefficient option 2 provided better agreement with observations. Selection of this option reduced predicted concentrations by 25 percent or more at some receptors.

BCKO3 - EPA used files of measured hourly ozone concentrations to establish background values, however, the BCKO3 value is substituted by Calpuff when hourly data are missing. Based on local monitoring data the IWAQM value of 80 ppb appears to be too high for North Dakota conditions, and therefore was reset to 30 ppb.

BCKNH3 - The value of 2 ppb reflects the annual average of local, unbiased monitoring data.

XSAMLEN - This value was set lower than the IWAQM recommendations to improve model resolution by increasing the number of puffs and decreasing mass per puff. The only negative consequence for revising this option would be extra computer processing time due to more puffs on the grid.

XMAXZI - Value was increased to 4000 m for consistency with ZIMAX/ZIMAXW setting in Calmet.

MPDF- This option should be deployed when dispersion option 2 is selected.

Emission Inventory for Class I Increment Analysis

In general, the source emission inventory for any increment analysis consists of all increment-affecting sources[13]. Specifically, this would include actual emissions from:

(1) any major stationary sources for which construction began after the major source baseline date (which, for SO_2 is January 6, 1975);

(2) any existing major stationary sources having undergone construction (i.e., a physical change or change in the method of operation) after the major source baseline date;

(3) any existing stationary sources having undergone a physical change or change in the method of operation, or having increased hours of operation or capacity utilization, after the minor source baseline date;

(4) any new stationary sources which were constructed after the minor source baseline date; and

(5) any changes in emissions from area and mobile sources since the minor source baseline date.

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13 New Source Review Workshop Manual, Part I, Chapter C, Section IV.C.2, p. C.35, Draft October 1990, EPA, Office of Air Quality Planning and Standards, Research Triangle Park, NC 27711, http://www.epa.gov/ttnnsr01/gen/wkshpman.pdf.

The "minor source baseline date" is defined as the earliest date after the "trigger date" (which for SO2 is August 7, 1977) that a major stationary source or major modification submits a complete PSD permit application. The minor source baseline date is set for the baseline area for the increment pollutant which the source would emit in significant amounts. (See 40 CFR 51.166(b)(14)(ii) and (iii), 40 CFR 52.21(b)(14)(ii) and (iii).) The applicable minor source baseline date in any increment analysis is the minor source baseline date *for the area that is being modeled for impacts*. The SO_2 minor source baseline date was triggered for the North Dakota "Rest of State" (Air Quality Control Region 172) SO_2 attainment area on December 17, 1977. So, for assessing the impacts in Theodore Roosevelt National Park and Lostwood Wilderness Area (both included in Air Quality Control Region 172), the applicable minor source baseline date is December 17, 1977. The SO_2 minor source baseline date for the Medicine Lakes Wilderness Area and the Fort Peck Indian Reservation in Montana was triggered on March 26, 1979, over a year later. Therefore, two emission inventories were compiled for this analysis: the inventory for the North Dakota Class I areas includes all increment-affecting sources based on a minor source baseline date of December 17, 1977 and the inventory for the Montana Class I areas includes all increment-affecting sources based on a minor source baseline date of March 26, 1979. Note that the NDDH did not develop a separate inventory for the Montana Class I areas in their 1999 draft modeling analysis or in the 2002 analysis. Their results are based only on North Dakota's December 17, 1977 minor source baseline date.

The two inventories include increment consuming, as well as increment expanding sources and consist of all major PSD sources located within 250 km of each Class I area as well as minor sources located within 50 km of each North Dakota Class I area[14]. The major source inventory includes increment consuming emissions from eight coal-burning power plants (one of which is located in Montana), four gas processing plants, a coal gasification plant and a refinery as well as increment expanding emissions from four major sources that shut down after the applicable minor source baseline dates.

Modeled emissions (i.e., increment consuming/expanding emissions) are determined by subtracting base year emissions from current year emissions, for each source. For sources constructed after the applicable baseline date, modeled emissions are the source's current year emissions minus zero emissions in the base year (i.e., all emissions are modeled as increment consuming). For sources shut down after the applicable baseline date, modeled emissions are zero emissions in the current year minus the source's base year emissions (i.e., all emissions are modeled as increment expanding).

3.1 Overview of Emission Changes in Response to Comments on Draft Report

3.1.1 90th Percentile Emission Rate

[14] The minor source inventory consists primarily of emissions from oil and gas facilities located in North Dakota. At the time of this report, emission and stack data were not available for the oil and gas production facilities found in the vicinity of Medicine Lakes Wilderness Area and Fort Peck Indian Reservation in Montana.

EPA received several comments on the use of the 90th percentile emission rate. Dakota Resource Council (DRC) commented that EPA should use the 100th percentile emission rate. DRC believes "in a time of peak electricity demand and, especially, when demand exceeds supply which has occurred fairly often over the last few summers, it is very likely that all electrical generating units will be operating at maximum capacity at the same time." In addition, DRC commented that applying a peak-to-mean ratio to estimate 90th percentile emissions in the base year does not account for changes in peak electricity demand from the base year to today. Several of the affected sources commented that EPA should use annual average emissions. The NDDH also commented that EPA should use annual average emissions, and commented that applying a peak-to-mean ratio to estimate 90th percentile emissions in the base year does not account for changes in sulfur content from the base year to today.

EPA continues to believe that, for a cumulative increment analysis such as this, the 90th percentile emission rate is the best representation of actual emissions. For this modeling analysis, EPA believes this technique is more appropriate than that recommended in our Guideline. As indicated in our draft report, EPA found that the 90th percentile cumulative emission rate (i.e., the sum of all of the 90th percentile emission rates at each facility) did actually occur several times during the 1999-2000 time period (whereas the 100th percentile cumulative emission rate did not). In reviewing the 2001 and 2002 CEM data the results are very similar to 1999-2000. The 90th percentile of the 24 hour averages are slightly higher than the maximum cumulative total that actually occurred on any one day, however, there were numerous periods when hourly cumulative emissions exceeded the 90th percentile values used in the current modeling. Given that, and the fact that the power plants are primarily used as base-load facilities, EPA believes this is the most representative method for determining current year emissions while still providing a reasonable estimate of cumulative peak emission conditions that may recur in the future.

In order to maintain consistency between the base year inventory and the current year inventory, EPA continues to believe that applying a peak-to-mean ratio from the current year to the base year to estimate 90th percentile emissions in the base year is appropriate. While the sulfur content and the peak electricity demand may differ from the base year to today, EPA believes that the alternative methods for calculating base year emissions - using the annual average emission rates or using the allowable emission rates for the base year period - are not acceptable since neither is consistent with the near-maximum actual emission rate used in the current year inventory.

3.1.2 Additional Sources to be Included in Inventories

The NDDH and several industry representatives pointed out two additional sources that were not included in the inventories in EPA's draft report - the Lignite Gas Plant and the Mandan Refinery.

EPA has included, in this May 2003 version of our report, NDDH's base year emission estimates for the Lignite Gas Plant which are based on actual emissions data from 1976-1977 (i.e., average processing rates and H_2S content of the inlet gas).

EPA has also included NDDH's base year emission estimates for the Mandan Refinery which are

based on the 1976 annual emission inventory. An inventory is not available for 1977 but the refinery indicated, in a September 13, 2001 letter to the NDDH, that 1976 emissions are representative of both 1976 and 1977 emissions. The only exception to this is the use of a revised Ultraformer fuel gas H_2S content. The refinery indicated that the 1976 number does not include sulfur in the fuel gas from the stripper and provided estimates for these emissions to include in the base year inventory.

Without a 1977 inventory for the Mandan Refinery, EPA is basing emission estimates for the Montana Class I areas on 1976 data (which, as stated above, the refinery claims are representative of 1977 emissions) and 1978 data. The 1978 data were obtained from the NDDH. According to the NDDH, 1978 was a "turnaround year for the facility and is not considered normal operations." While that may be the case for a 1976-1977 baseline period (i.e., for the North Dakota Class I areas), EPA will consider it to be representative of normal operations for a 1977-1978 baseline period (i.e., for the Montana Class I areas).

Finally, EPA obtained and reviewed 2000 and 2001 emission estimates from the NDDH for these sources for use in the current year inventory.

At the time the EPA draft modeling study was prepared in late 2001, a comprehensive SO2 emission inventory for oil and gas related facilities in western North Dakota was not available. NDDH prepared a preliminary estimate of oil and gas emissions for use in the Department's April 2002 Calpuff modeling study but has not yet refined those estimates. EPA obtained the oil and gas emissions files used in NDDH's April 2002 study and has incorporated them into the current study. As discussed below, EPA believes that the State's preliminary oil and gas inventory significantly overstates the level of SO2 emissions in the 1976-1977 baseline period. Overestimation of the base year emissions would create more increment expansion credit than is justified, hence the total amount of increment consumption calculated in this study may be too low. EPA intends to supplement the current study with updated modeling results when more reliable oil and gas emissions estimates become available.

EPA concerns with the State's preliminary oil and gas estimates are discussed in an April 3, 2001 letter to NDDH [15], and in EPA's May 24, 2002 public hearing comments[16] . One major concern with the oil and gas inventory was that the estimates were based on the average of peak short-term emission rates, rather than annual average emission rates. This is a problem in estimating emissions from oil and gas sources because the sources may only operate for a period of weeks or months at a time, but under the State's approach they would get increment expansion credit as if they were operating continuously for the entire year. With the very large number of such sources, we believe that it is unrealistic to assume that they would all operate at peak levels all the time.

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[15] Letter from Richard R. Long, Director, Air and Radiation Program, EPA Region VIII, to Terry O'Clair, Director, Division of Air Quality, State of North Dakota Department of Health (April 3, 2002) (on file at EPA Region VIII, Denver, Colorado).

[16] EPA Comments on North Dakota Department of Health's Proposed Determination Regarding the Adequacy of the SIP to Protect PSD Increments for Sulfur Dioxide, U.S. Environmental Protection Agency, May 24, 2002.

This concern was highlighted by the fact that a 1983 State study of oil and gas emissions for 1981 and 1982 showed emissions approximately 50 percent lower than the current estimates.[17] Based on trends in SO_2 monitoring data and oil production data SO_2 emissions should have been even lower in 1976 - 1977.

In reviewing the discussion in the State's PSD Baseline Emission Rates document[18], the text indicates that the Williston Basin Study (WBS) was used to calculate oil and gas SO_2 emission rates from November 1987 to March 1988 and that these data were used directly to estimate 1976 to 1977 emissions. The only major adjustments were that the WBS emissions were only applied to wells actually in operation in 1977, and in instances where 1987-1988 data were unavailable, field average values from the WBS were used. EPA is concerned that direct use of WBS 1987 to 1988 data will overestimate base year emissions and the amount of increment expansion credit. The concern can be seen by referring to the Billings County monthly oil production data, and the Statewide oil production data provided by the North Dakota Industrial Commission (available at http://explorer.ndic.state.nd.us/stats/statistics.html). In both cases the volume of oil produced in 1988 is nearly double that produced in 1976-1977. Obviously the much lower production rates in 1976-1977 would have tended to produce lower emissions than the State's estimate using 1988 WBS data.

The issue of temporary emissions sources is also a concern. Some oil field sources, such as flares may only operate for a total of three or four months. EPA believes the State has not demonstrated the legal authority to include temporary emissions of this nature as increment-expansion sources.

Because individual well site oil and gas facilities are numerous and generally have very small SO2 emissions, they were included in the modeling if they were located within 50 km of any Class 1 area. This distance limit is consistent with NDDH's 1999 and 2002 Calpuff modeling analyses. EPA used NDDH developed software CALSMOG2 as a postprocessor on the Calpuff output files to facilitate integration of the modeling results for the hundreds of oil and gas point sources into the overall modeling results.

3.1.3 Updated Emissions for Increment Expanding Sources

The NDDH commented that EPA should use actual emission estimates for the current year inventory for the Tioga Gas Plant, as opposed to the allowable emissions used in EPA's draft report (and the NDDH's 1999 draft modeling analysis).

EPA obtained and reviewed revised [actual] current year emission estimates for the Tioga Gas

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[17] North Dakota State Department of Health, Division of Environmental Waste Management and Research, Division of Environmental Engineering, Final Report - Sulfur Dioxide Emissions Inventory for Sources Near the Theodore Roosevelt National Park, Prepared for National Park Service (February 1983) (on file at EPA Region VIII, Denver, Colorado).

[18] North Dakota Department of Health, Draft Prevention of Significant Deterioration - Sulfur Dioxide - Baseline Emission Rates, at 23 (April, 2002) (*available at* http://www.health.state.nd.us/psd/).

Plant from the NDDH for use in the May 2003 version of this report. We used 1977 inventory data for baseline emissions; 1976 data were not available for this source.

The NDDH and several industry representatives commented that EPA should use 1978 and 1979 emissions to estimate baseline emissions for the Royal Oak Briquetting Plant. According to the State, the source had initiated or completed construction of two new furnaces prior to the baseline date to accommodate this increase, and therefore in their April 2002 modeling study, the State used a period *after* the 1976-1977 baseline period to determine emissions (1978-1979). The consideration of anticipated production rates by the State increased emissions estimates for the Royal Oak Briquetting facility from 2400 tons/year in the State's 1999 modeling study (based on actual data from the 1976-1977 period) to 9600 tons/year in their April 2002 modeling study. EPA believes that using another two-year period (other than 1976-1977) to estimate baseline emissions is not justified. EPA does not consider the concept of *anticipated* production rates to be applicable in cases where *actual* source emissions are well documented for the 1976-1977 baseline period. Such projections might be useful in instances where base year emissions are unknown. The proposed furnaces did not affect actual emissions in the 1976-1977 period. For the reasons noted above, EPA believes that the 2400 ton/year estimate using actual 1976-1977 source data is more appropriate and consistent with the PSD regulations.

An important requirement is that if an alternative two-year period is selected to represent normal source operation, it should represent normal operation *for the baseline period, not normal operation for the life of the source.* EPA does not support any deviations from the 1976-1977 base year unless data from alternative years provides a better estimate of emissions that actually occurred in the 1976-1977 time period. The only exception would be if some serious event occurred during those two years that would be extremely unlikely to recur in the future (such as strike, major industrial accident, or retooling). None was identified.

A similar issue was raised by Basin Electric in recommending that 1977-1978 be used in calculating baseline emissions for Unit 1 and 1978-1979 for Unit 2. During 1976 and 1977 there were a number of activities at Leland Olds the company believes were not indicative of normal source operation, such as manufacturer modifications to equipment, turbine modifications, generator ground faults, turbine blade failure, scheduled outages, etc. Generally EPA has determined that use of a different baseline year is limited to those cases where catastrophic occurrences such as strike or major industrial accidents have occurred, and does not apply to circumstances of the type noted by Basin. A May 3, 1976 letter from Basin to NDDH supports this view in stating that "The plant has recently operated consistently near the nameplate load of 440 megawatts". Thus EPA calculated Leland Olds emissions based on 1976-1977 activities data.

In a related argument, an industry commentor recommended using coal sulfur content data averaged over the life of the coal mine to calculate baseline emissions, rather than the two-year average data from the 1976-1977 base period. As noted above, EPA believes that use of the 1976 and 1977 data would provide a better estimate of conditions that occurred in the base period than long-term average coal sulfur data.

3.1.4 Variance Sources

Several commentors on the EPA draft report stated that EPA should not consider PSD increment consumption from sources that received variances from the Federal Land Manager (FLM) in the past. There are two sources which received variances from the FLM that are operating today. Those facilities are the Little Knife Gas Plant near Killdeer, ND, and the Dakota Gasification Company near Beulah, ND. These FLM variances certified that at the time these proposed sources received PSD permits, the proposed sources would not adversely affect the air quality related values of only Theodore Roosevelt National Park and the Lostwood Wilderness Area (i.e., there were no variances granted for the two Class I areas in Montana).

EPA believes that the effect of the variances is limited. The provision extends only to the new construction (source or modification) under consideration, allowing that construction to go forward despite a modeled Class I increment violation. Nothing in the statute suggests that such a source does not contribute to increases in concentrations of pollutants. The Class I variance provisions of the Clean Air Act and the North Dakota Air Pollution Control Rules allow the State to issue a PSD permit to a particular source despite a modeled increment violation, but that the State is still required to correct the Class I increment violation through a revision to the SIP. Therefore, EPA has included current year emissions from these two sources in the modeling and they are considered increment consuming sources. A more detailed discussion of this issue is contained in EPA's May 24, 2002 comments document to NDDH.

3.1.5 Consideration of Alternative Methods for Calculating Increment Inventory

A number of commentors on the EPA draft study recommended the use of annual average emissions for calculating increment consumption, rather than the near-maximum 24-hour rates used in the study. This not consistent with 40 CFR Part 51, Appendix W which requires that averaging times for emission rates used in PSD modeling must reflect the averaging time of the PSD increments in order to ensure protection of both the short-term and long-term increments. Use of annual average emission rates in the increment modeling will underestimate increment consuming emissions and therefore will not ensure protection of the 3- and 24-hour maximum allowable increases in concentrations of SO_2. For example, the use of annual emissions would not consider a summer heat wave situation in which local power plants are operating at or near peak load, coincident with winds blowing toward Class I areas. Annual average emissions would be appropriate for modeling the *annual* PSD increment, however, both EPA's January 2002 analysis and the State's 1999 analysis showed that the annual increment is not threatened at this time. In our modeling analysis, the 90th percentile of measured 24-hour average emissions were used to estimate the maximum, or near maximum, emissions for the major increment-consuming sources. In EPA's 90th percentile approach, 24-hour average emissions were approximately 50 percent higher than the annual average emission rate divided by 365. Thus, the proposed approach appears to not be protective of the 3- and 24-hour average Class I increments.

A commentor stated that continuous emissions monitoring system (CEMS) data from EPA's Acid Rain Data base are biased high, and are higher than emissions calculated based on AP-42

emission factors. Because in EPA's January 2002 modeling study CEMs data were used to determine current emissions, and AP-42 factors were used in the baseline years, the commentor felt that increment-consuming emissions were overestimated in EPA's study. EPA disagrees with the commentor and we do not believe increment-consuming emissions have been overstated. We consider the CEMs data to be the best data available for use in increment analysis and we have seen no evidence from industry that would support the contention of a CEMs bias for the sources included in this analysis.[19] The perceived difference in the two methods may be related to problems in the AP-42 data rather than CEMs bias.[20] In accordance with the Acid Rain Program regulations, the quality-assured CEMS data are certified by the company's Designated Representative, and in the absence of any approved source petition, as provided for under the Acid Rain Program, EPA considers these quality-assured data to be accurate.[21]

3.2 Current Year Inventory

Emissions for the current year inventory are based on actual emissions reflected by normal source operation for a period of two years. The two-year study period should generally be the most recent two years, provided that the two-year period is representative of normal source operation. Another two-year period may be used, only if that other period of time is more typical of normal source operation than the two years immediately preceding the date of concern (see 45 FR 52718). For the most part, the current year inventory for this analysis is based on continuous emission monitor system (CEMS) data from 2000 and 2001 as reported to the Acid Rain Database.

Following is a brief description of each major source that was constructed after the major source baseline date for SO_2 (see Section 3.3 for similar descriptions on the baseline sources, all constructed before the major source baseline date). Information is based on data from EPA's Acid Rain Database (see http://www.epa.gov/airmarkets/picturethis/index.htm):

Basin Electric Power Cooperative - Antelope Valley Station
Unit 1 - 435 MW, tangentially-fired lignite boiler, SO_2 control - (dry lime) flue gas desulfurization (FGD)
Unit 2 - 435 MW, tangentially-fired lignite boiler, SO_2 control - (dry lime) FGD

Otter Tail - Coyote Station
Unit 1 - 450 MW, cyclone-fired lignite boiler, SO_2 control - (dry lime) FGD

Great River Energy - Coal Creek Station

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[19] Letter from Richard Long, Director, Air and Radiation Program EPA Region VIII, to Terry O'Clair, Director, Division of Air Quality, North Dakota Department of Health (March 15, 2002) (on file with EPA Region VIII, Denver, Colorado).

[20] United States Environmental Protection Agency, Office of Air Quality Planning and Standards, Compilation of Air Pollutant Emission Factors AP-42, Fifth Edition,, Volume I: Stationary, Point and Area Sources, Pub. No. AP-42 (*available at* http://www.epa.gov/ttn/chief/ap42/).

[21] 40 C.F.R. Part 75.

Unit 1 - 506 MW, tangentially-fired lignite boiler, SO_2 control - (dry lime) FGD
Unit 2 - 506 MW, tangentially-fired lignite boiler, SO_2 control - (dry lime) FGD

PPL Corp. - Colstrip (Montana)
Unit 3 - 778 MW, tangentially-fired boiler, SO_2 control - (wet lime) FGD
Unit 4 - 778 MW, tangentially-fired boiler, SO_2 control - (wet lime) FGD

Great River Energy - Stanton Station
Unit 10 - 60 MW, tangentially-fired lignite boiler, SO_2 control - (dry lime) FGD
Hourly CEMS data for 2000 and 2001 for each of the eight power plants in the major source inventory (including four baseline sources) were obtained from EPA's Acid Rain Program. For each source, daily average emissions (24-hour averages) were calculated. The 90th percentile emission rate for each source was determined by ranking (from highest to lowest) the source's 24-hour average emission rates over two years - for a total of 730 emission rates (where the data record is 100% complete) - and selecting the 73rd highest 24-hour average emission rate from the list. This single emission rate was then modeled for every 24-hour period over the five years of meteorology data used in the model.

There is one exception to the above method for determining current year emissions. PPL Corporation's Colstrip power plant in Montana has four units. Units 1 and 2 were both constructed before the major source baseline date for SO_2 (January 6, 1975). We did not obtain baseline emission information for these units but know, from reviewing the available data in the Acid Rain Database, that emission trends from 1980 to today are relatively flat or even slightly down. This suggests that increment-consuming emissions would be low and so we did not include these units in the inventories. Units 3 and 4 were both constructed after the major source baseline date for SO_2; emissions for both units were obtained from the Acid Rain Database and are based on 2000 and 2001 CEMS data divided by 365 days to estimate 24-hour emissions. A more refined analysis could be made of Units 3 and 4 increment-consuming emissions, to be consistent with the methodology used for major North Dakota sources, however, such an analysis did not seem warranted given the units' negligible contribution to increment concentrations in any of the Class I areas modeled.

Current year emissions for the power plants are summarized in Table 3-1.

Table 3-1
CURRENT YEAR SO_2 EMISSIONS FOR POWER PLANTS
Based on CEM data from EPA's Acid Rain Database

Source	2000 Actual Emissions			2001 Actual Emissions			**Current Year Emissions**	
	max 24 hour [lb/hr]	90 % 24 hour [lb/hr]	annual [TPY]	max 24 hour [lb/hr]	90 % 24 hour [lb/hr]	annual [TPY]	**2yr-90% 24 hour [lb/hr]**	**2-yr avg annual [TPY]**
Basin Electric Power Cooperative - Antelope Valley Station								
Units 1 + 2	4940	3291	13047	5146	3417	12066	**3440**	**12557**
Otter Tail - Coyote Station								
Unit 1	5115	4655	14521	5115	4804	16361	**4755**	**15441**
Great River Energy - Coal Creek								
Unit 1	5287	4195	14332	5733	4328	14591	**4269**	**14462**
Unit 2	4608	3552	12817	4969	3331	11608	**3429**	**12213**
PPL Corp. - Colstrip (Montana)								
Unit 3[1]	n/a	n/a	2859	n/a	n/a	2876	**655**	**2868**
Unit 4[1]	n/a	n/a	2315	n/a	n/a	2915	**597**	**2615**
CELP (Colstrip Energy Limited Partnership) (Montana)								
Boiler	n/a	n/a	1839	n/a	n/a	1839	**420**	**1839**
Minnkota Power Cooperative - Milton R. Young Station								
Unit 1	7082	5599	18095	7191	6314	23074	**6087**	**20585**
Unit 2	6838	6089	21134	5521	4563	12463	**5749**	**16799**

Source	2000 Actual Emissions			2001 Actual Emissions			**Current Year Emissions**	
	max 24 hour [lb/hr]	90 % 24 hour [lb/hr]	annual [TPY]	max 24 hour [lb/hr]	90 % 24 hour [lb/hr]	annual [TPY]	**2yr-90% 24 hour [lb/hr]**	**2-yr avg annual [TPY]**
Basin Electric Power Cooperative - Leland Olds Station								
Unit 1	5970	4965	16864	5679	5153	15296	**5085**	**16080**
Unit 2	11796	9877	28587	12205	10708	36117	**10354**	**32352**
Montana-Dakota Utilities Co. - Heskett Station								
Unit 1	537	348	1022	473	332	1029	**342**	**1026**
Unit 2	1080	822	1778	1476	861	2599	**849**	**2189**
Great River Energy - Stanton Station								
Unit 1	3047	2523	7017	3371	2753	9165	**2669**	**8091**
Unit 10	402	307	972	377	319	1216	**316**	**1094**

[1] 24-hour current year emissions are based on annual CEMS data divided by 365 days. See discussion above.

CEMS data for 2000-2001 were not available for the gas processing plants (Grasslands Gas Plant, Little Knife Gas Plant, Tioga Gas Plant and Lignite Gas Plant), the coal gasification plant (Greatplains Synfuels Plant), the refinery (Mandan Refinery) and CELP, so EPA based emissions on the annual emission inventory reports submitted to the NDDH. Due to a lack of good short-term emissions data for these sources, 24-hour emission rates are based on annual emissions divided evenly over 365 days.

Current year emissions for these non-power plant sources are summarized in Table 3-2.

Table 3-2
OTHER SO_2 CURRENT YEAR EMISSIONS
Based on annual emission inventory reports provided to NDDH

Units	2000 Actual Emissions		2001 Actual Emissions		**Current Emissions**	
	annual emissions [TPY]	24-hr emissions [lb/hr]	annual emissions [TPY]	24-hr emissions [lb/hr]	**annual [TPY]**	**24-hr [lb/hr]**
Mandan Refinery (baseline source, increment expanding emissions)						
Boilers	599	137	155	35	**377**	**86**
Crude Furnace	381	87	11	3	**196**	**45**
FCCU	4079	931	4737	1082	**4408**	**1006**
Ultraformer Furnaces	64.5	15	76.4	17	**70**	**16**
Alkylation Furnaces	30.5	7	35.5	8	**33**	**8**
SRU Incinerator + Flare	188	43	240	55	**214**	**49**
Lignite Gas Plant (baseline source, increment expanding emissions)						
Flare	463	106	584	133	**524**	**120**
Tioga Gas Plant (baseline source, increment expanding emissions)						
Sulfur Recovery Unit	1337	305	2132	487	**1337**	**305**
Grasslands Gas Plant						
Incinerator Stack + Flare	1150	263	538	123	**1150**	**263**
Petro-Hunt, LLC - Little Knife Gas Plant						
Incinerator Stack + Flare	367	84	562	128	**367**	**84**
Dakota Gasification Company - Great Plains Synfuels Plant						
Main Stack	4605	1051	2816	643	**4605**	**1051**
Bypass Stack	3743	855	5727	1308	**3743**	**855**
Start-up Flare	1733	396	396	90	**1733**	**396**
Main Flare	779	178	835	191	**779**	**178**
Back-up Flare	543	124	248	57	**543**	**124**
TOTAL					**20079**	**4584**

3.3 Base Year Inventory

As in the current year inventory, emissions for the base year inventory are generally based on actual emissions reflected by normal source operation for a period of two years. The two-year study period should generally be the two years preceding the minor source baseline date, provided that the two-year period is representative of normal source operation. Another two-year period may be used, only if that other period of time is more typical of normal source operation than the two years immediately preceding the baseline date (see 45 FR 52718, August 7, 1980). EPA rules and guidance allow the potential to emit to be used if little or no operating data are available, as in the case of a permitted emission unit constructed before the major source baseline date but not yet in operation at the time of the minor source baseline date (see 40 CFR 51.166(b)(13), p. C.11 of the NSR workshop manual[9], and 45 FR 52718, col. 3, August 7, 1980).

Four of the seven coal-burning power plants in North Dakota commenced construction before the major source baseline date for SO_2 (January 6, 1975). These include Minnkota Power Cooperative's Milton R. Young Station (Units 1 and 2), Basin Electric Power Cooperative's LeLand Olds Station (Units 1 and 2), Montana-Dakota Utilities Company's Heskett Station (Units 1 and 2) and Great River Energy's Stanton Station (Unit 1). These units are all included in the major source base year emission inventory. No major sources in this analysis that were built before the major source baseline date reported any physical change or change in the method of operation after the major source baseline date but before the minor source baseline dates (i.e., all emissions prior to the applicable minor source baseline dates are considered to be baseline emissions).

Following is a brief description of each baseline source, based on information from EPA's Acid Rain Database (see http://www.epa.gov/airmarkets/picturethis/index.htm):

Minnkota Power Cooperative - Milton R. Young Station
Unit 1 - 257 MW, lignite-fired cyclone boiler, uncontrolled for SO_2
Unit 2 - 477 MW, lignite-fired cyclone boiler, SO_2 control - (dry alkali) flue gas desulfurization

Basin Electric Power Cooperative - Leland Olds Station
Unit 1 - 216 MW, lignite-fired dry bottom boiler, uncontrolled for SO_2
Unit 2 - 440 MW, lignite-fired cyclone boiler, uncontrolled for SO_2

Montana-Dakota Utilities Co. - Heskett Station
Unit 1 - 25 MW, lignite-fired, uncontrolled for SO_2
Unit 2 - 75 MW, lignite-fired boiler retrofitted to a fluidized bed combustor in 1987, uncontrolled for SO_2

Great River Energy - Stanton Station
Unit 1 - 187 MW, lignite-fired dry bottom boiler, uncontrolled for SO_2

3.3.1 Base Year Inventory for North Dakota Class I Areas

In general, the base year inventory for the North Dakota Class I areas is based on actual emissions averaged over the two-year period 1976-1977. For all baseline power plant emissions we used AP-42 emission factors for uncontrolled lignite-fired boilers (see AP-42[22], section 1.7, Table 1.7-1).

The only data available to us for these baseline power plant sources for the years 1976 and 1977 are what is reported to the State in the Annual Emission Inventory Reports (e.g., coal use, sulfur content, coal feed rates, etc.). Based on this information, short-term emissions were calculated by determining annual emissions (based on an AP-42 emission factor (in lb_{SO2}/ton_{coal}), average sulfur content (in wt. %) and annual coal usage (in ton_{coal}/yr)) and then applying the peak-to-mean ratio from the current year CEMS emissions to the mean annual base year emissions to get peak base year emissions. Specifically, the ratio of the annual average emission rate from the 2000-2001 CEMS data to the 90th percentile 24-hr emission rate (from 2000-2001 CEMS data) is applied to the annual average emission rate in the base year to calculate the 24-hr emission rate in the base year. Since short-term emission rates in the current year inventory are based on the 90th percentile of the 24-hour average (see Section 3.2), this option gives the best estimate of the 90th percentile 24-hour emission rate in the base year and is, therefore, consistent with the short-term emissions used in the current year inventory.

EPA believes any increment analysis should follow the same methodology for determining emissions in the base year as in the current year, particularly where like data are available, as is the case here. Using the same methodology allows an objective comparison (and use) of the two data sets. To do otherwise does not provide "comparable" data sets. If different methodologies were used to determine emissions for the base year and the current year, comparing the two data sets would produce inappropriate conclusions since the data sets had been derived using different methodologies.

Annual average emissions are based on an AP-42 emission factor for uncontrolled lignite-fired boilers of 30 S (see AP-42, section 1.7, Table 1.7-1). There is an alternative emission factor of 34(S) that AP-42 recommends when the amount of sodium in the ash is less than 2 percent, however, the available data showed that the use of the 34(S) factor was not justified for the baseline sources modeled in this study. Annual Emission Inventory Reports for each baseline power plant were obtained from the NDDH for 1976 and 1977. From these reports, annual coal usage and average sulfur content data were used to calculate annual average SO_2 emissions. For example, annual average base year SO_2 emissions for Minnkota's Milton R Young Unit 1 are:

$$SO_2\ emissions_{1976}\ [TPY] = 30 * (0.52\%)\ \frac{lb_{SO2}}{ton_{coal}} * 1{,}581{,}000\ \frac{ton_{coal}}{yr} * \frac{1\ ton_{SO2}}{2000\ lb_{SO2}} = 12{,}332\ \frac{ton_{SO2}}{yr}$$

$$SO_2\ emissions_{1977}\ [TPY] = 30 * (0.63\%)\ \frac{lb_{SO2}}{ton_{coal}} * 1{,}527{,}511\ \frac{ton_{coal}}{yr} * \frac{1\ ton_{SO2}}{2000\ lb_{SO2}} = 14{,}435\ \frac{ton_{SO2}}{yr}$$

[22] Compilation of Air Pollutant Emission Factors, AP-42, Fifth Edition, Volume I: Stationary Point and Area Sources, January 1995, EPA, Office of Air Quality Planning and Standards, Research Triangle Park, NC 27711, http://www.epa.gov/ttn/chief/ap42/index.html.

$$2\,yr\,average\,SO_2\,emissions[TPY] = \frac{(12,332 + 14,435)}{2} = \underline{\underline{13,383\,TPY}}$$

Short-term emissions are then calculated based on the peak-to-mean ratio from current year emissions. For example, short-term SO_2 base year emissions for Minnkota's Milton R Young Unit 1 boiler are:

$$peak-to-mean\,ratio_{2000-2001} = \frac{6087\frac{lb}{hr}(90^{th}\%\,24hr\,avg_{2000-2001}) * \frac{8760\,hr}{yr} * \frac{ton}{2000\,lb}}{20,585\frac{ton}{yr}(2yr\,annual\,avg_{2000-2001})} = 1.3$$

$$base\,year\,SO_2\,emissions[\frac{lb}{hr}] = 13,383\frac{ton}{yr} * 1.30 * \frac{yr}{8760hr} * \frac{2000lb}{ton} = \underline{\underline{3972\frac{lb}{hr}}}$$

We used the above method for calculating base year emissions for the power plants, with one exception. Minnkota's Milton R Young Unit 2 had only been in operation for 9 months as of the minor source baseline date and those 9 months do not appear to be representative of normal operating conditions. The unit was apparently out of compliance with its allowable emissions for many months after the unit began operation. Considering that we do not have two years of actual emissions at the time of the minor source baseline date for this unit, as well as the fact that the unit really did not begin "normal operations" until after the baseline date was triggered, we believe it is appropriate in this situation to consider the allowable emissions of Minnkota's Unit 2 as its emissions at the time of the baseline date (see 45 FR 52718, col. 3, August 7, 1980). Furthermore, since any emissions increases above a source's allowable emission rate at the time of the minor source baseline date must be considered as increment-consuming emissions, it would not be appropriate to use Unit 2's actual emission rate at the time of the minor source baseline date as the baseline emission rate. Therefore, we modeled a short-term emission rate of 5635 lb/hr (the allowable emission rate) for this unit.

Where CEMS data were not available to calculate a peak-to-mean ratio (e.g., the gas plants and the refinery), short-term emissions were calculated by dividing the annual average emissions over 365 days.

Baseline emissions for the Class I areas in North Dakota are summarized in Tables 3-3 and 3-4.

Table 3-3

POWER PLANT SO_2 BASELINE EMISSIONS FOR **NORTH DAKOTA** CLASS I AREAS

Based on AP-42 and annual emission inventory reports provided by ND for 1976-1977

SO_2 minor source baseline date = December 19, 1977

Source	Emission Factor	1976 Actual Emissions			1977 Actual Emissions			**Baseline Emissions**	
	[lb_{SO2}/ton_{coal}]	avg. S [%]	coal burned [TPY]	annual emissions [TPY]	avg. S [%]	coal burned [TPY]	annual emissions [TPY]	**annual [TPY]**	**24-hr[1] [lb/hr]**
Minnkota Power Cooperative - Milton R. Young Station									
Unit 1	30(S)	0.52	1581000	12332	0.63	1527511	14435	**13383**	**3972**
Unit 2[2]	n/a	n/a	n/a	24682	n/a	n/a	24682	**24682**	**5635**
Basin Electric Power Cooperative - Leland Olds Station									
Unit 1	30(S)	0.45	1255995	8478	0.44	1306785	8625	**8551**	**2714**
Unit 2	30(S)	0.45	1958680	13221	0.44	1964660	12967	**13094**	**4185**
Montana-Dakota Utilities Co. - Heskett Station									
Unit 1	30(S)	0.75	159196	1791	0.68	171162	1746	**1768**	**589**
Unit 2	30(S)	0.75	376017	4230	0.68	406145	4143	**4186**	**1625**
Great River Energy - Stanton Station									
Unit 1	30(S)	0.65	746205	7275	0.64	737106	7076	**7176**	**2359**
TOTAL								**72841**	**21080**

[1] Based on the ratio of annual average emission rate (from 2000-2001 CEM data) to the 90th percentile 24-hr emission rate (from 2000-2001 CEM data) applied to the annual average emission rate in the base year.

[2] Unit 2 had only been operating 9 months as of the minor source baseline date (12/19/77) and those 9 months were not considered representative of actual operation. Therefore, allowable emissions were used to determine baseline emissions. See 45 FR 52718, col. 3.

Table 3-4
OTHER SO_2 BASELINE EMISSIONS FOR **NORTH DAKOTA** CLASS I AREAS
Based on annual emission inventory reports provided to ND
SO_2 minor source baseline date = December 19, 1977

Units	1976 Actual Emissions		1977 Actual Emissions		**Baseline Emissions**	
	annual emissions [TPY]	24-hr emissions [lb/hr]	annual emissions [TPY]	24-hr emissions [lb/hr]	**annual [TPY]**	**24-hr [lb/hr]**
Mandan Refinery						
Boilers	2244	512	n/a[1]	n/a	**2244**	**512**
Crude Furnace	2410	550	n/a	n/a	**2410**	**550**
FCCU	4975	1136	n/a	n/a	**4975**	**1136**
Ultraformer Furnaces	60	14	n/a	n/a	**60**	**14**
Alkylation Furnaces	702	160	n/a	n/a	**702**	**160**
Lignite Gas Plant						
Flare	1241	283	1262	288	**1252**	**286**
Tioga Gas Plant						
Sulfur Recovery Unit	n/a[2]	n/a	4849	1107	**4849**	**1107**
TOTAL					**16492**	**3765**

[1] In a September 13, 2001 letter to the NDDH, BP indicated they could not locate an emission inventory for 1977. In that same letter, BP indicated that 1976 data would be representative of both 1976 and 1977.

[2] 1976 emission estimates are not available for the Tioga Gas Plant. Therefore, only 1977 emission estimates are used to determine baseline emissions.

3.3.2 Base Year Inventory for Montana Class I Areas

In general, the base year inventory for the Montana Class I areas was compiled using the same method as for the North Dakota Class I inventory. The only difference is the use of 1977 and 1978 emission inventory data for calculating the annual average emission rates. As discussed previously, the inventory for the Montana Class I areas includes all increment-affecting sources based on a minor source baseline date of March 26, 1979. While we still used allowable emissions for Minnkota's Milton R Young Unit 2 in 1977, we were able to calculate actual emissions for 1978. Since Unit 2 commenced construction after August 17, 1971, it was permitted according to the New Source Performance Standards (NSPS) in 40 CFR Part 60 Subpart D. Therefore, we calculated actual emissions for the unit based on this 1.2 lb_{so2}/mmBtu standard, the average heat

content of the coal in 1978 and the annual coal usage rate for that year. We then applied the peak-to-mean ratio from 2000-2001 CEMS data to calculate a short-term emission rate and averaged that with the 1977 allowable emission rate of 5635 lb/hr to arrive at a short-term emission rate for the unit for the base year.

Baseline emissions for the Class I areas in Montana are summarized in Tables 3-5 and 3-6.

Table 3-5
POWER PLANT SO_2 BASELINE EMISSIONS FOR **MONTANA** CLASS I AREAS
Based on AP-42 and annual emission inventory reports provided by ND for 1977-1978
SO_2 minor source baseline date = March 26, 1979

Source	Emission Factor [lb_{SO2}/ton_{coal}]	1977 Actual Emissions			1978 Actual Emissions			**Baseline Emissions**	
		avg. S [%]	coal burned [TPY]	annual emissions [TPY]	avg. S [%]	coal burned [TPY]	annual emissions [TPY]	**annual [TPY]**	**24-hr[1] [lb/hr]**
Minnkota Power Cooperative - Milton R. Young Station									
Unit 1	30(S)	0.63	1527511	14435	0.65	1427485	13918	**14176**	**4208**
Unit 2[2]	1.2 lb/mmBtu	n/a	n/a	24682	0.65	1956191	15087	**19884**	**5401**
Basin Electric Power Cooperative - Leland Olds Station									
Unit 1	30(S)	0.44	1306785	8625	0.74	1361539	15113	**11869**	**3767**
Unit 2	30(S)	0.44	1964660	12967	0.74	2435160	27030	**19999**	**6392**
Montana-Dakota Utilities Co. - Heskett Station									
Unit 1	30(S)	0.68	171162	1746	0.71	161755	1723	**1734**	**578**
Unit 2	30(S)	0.68	406145	4143	0.71	342560	3648	**3895**	**1512**
Great River Energy - Stanton Station									
Unit 1	30(S)	0.64	737106	7076	0.61	577004	5280	**6178**	**2031**
TOTAL								**77736**	**23888**

[1] Based on the ratio of annual average emission rate (from 2000-2001 CEM data) to the 90th percentile 24-hr emission rate (from 2000-2001 CEM data) applied to the annual average emission rate in the base year.

[2] Unit 2 had only been operating 9 months in 1977 and those 9 months were not considered representative of actual operation. Therefore, allowable emissions were used to determine 1977 emissions. See 45 FR 52718, col. 3. 1978 emissions are based on an emission limit of 1.2 lb_{SO2}/mmBtu for NSPS boilers (see 40 CFR Part 60 Subpart D) and an average heat content of 6427 Btu/lb_{coal}.

Table 3-6
OTHER SO_2 BASELINE EMISSIONS FOR **MONTANA** CLASS I AREAS
Based on annual emission inventory reports provided to ND
SO_2 minor source baseline date = March 26, 1979

Units	1977 Actual Emissions		1978 Actual Emissions		**Baseline Emissions**	
	annual emissions [TPY]	24-hr emissions [lb/hr]	annual emissions [TPY]	24-hr emissions [lb/hr]	**annual [TPY]**	**24-hr [lb/hr]**
Mandan Refinery[1]						
Boilers	2244	512	2168	495	**2206**	**504**
Crude Furnace	7385	1686	1537	351	**4461**	**1018**
FCCU						
Ultraformer Furnaces	60	14	4.7	1	**32**	**7**
Alkylation Furnaces	702	160	590	135	**646**	**147**
Lignite Gas Plant						
Flare	1262	288	3032	692	**2147**	**490**
Tioga Gas Plant						
Sulfur Recovery Unit	4849	1107	n/a[2]	n/a	**4849**	**1107**
TOTAL					**14341**	**3274**

[1] In a September 13, 2001 letter to the NDDH, BP indicated they could not locate an emission inventory for 1977. In that same letter, BP indicated that 1976 data would be representative of both 1976 and 1977. Data presented are based on the 1976 inventory.

[2] 1976 emission estimates are not available for the Tioga Gas Plant. Therefore, only 1977 emission estimates are used to determine baseline emissions.

3.4 Increment Inventories

Tables 3-7 and 3-8 summarize the increment consuming and increment expanding (shown as a negative number) emissions from the inventories in Section 3.2 Current Year Emissions and Section 3.3 Base Year Emissions.

Table 3-7

SO_2 INCREMENT INVENTORY FOR **NORTH DAKOTA** CLASS I AREAS

Source	Base Year Emissions		Current Year Emissions		Increment Consuming Emissions[1]	
	24-hr[2] [lb/hr]	annual [TPY]	24-hr[3] [lb/hr]	annual [TPY]	24-hour [lb/hr]	annual [TPY]
Basin Electric Power Cooperative - Antelope Valley Station						
Units 1+2	n/a	n/a	3,440	12,557	3,440	12,557
Otter Tail - Coyote Station						
Unit 1	n/a	n/a	4,755	15,441	4,755	15,441
Great River Energy - Coal Creek Station						
Unit 1	n/a	n/a	4,269	14,462	4,269	14,462
Unit 2	n/a	n/a	3,429	12,213	3,429	12,213
PPL Corp. - Colstrip (Montana)						
Unit 3	n/a	n/a	655	2868	655	2868
Unit 4	n/a	n/a	597	2615	597	2615
CELP (Colstrip Energy Limited Partnership) (Montana)						
Boiler	n/a	n/a	420	1,839	420	1,839
Minnkota Power Cooperative - Milton R.Young Station						
Unit 1	3,972	13,383	6,087	20,585	2,115	7,202
Unit 2[4]	5,634	24,682	5,749	20,585	115	(4,097)
Basin Electric Power Cooperative - Leland Olds Station						
Unit 1	2,714	8,551	5,085	16,080	2,371	7,529
Unit 2	4,185	13,094	10,354	32,352	6,169	19,258
Montana Dakota Utilities Co. - Heskett Station						
Unit 1	589	1,768	342	1,026	(247)	(742)
Unit 2	1,625	4,186	849	2,189	(776)	(1,997)
Great River Energy - Stanton Station						
Unit 1	2,359	7,176	2,669	8,091	310	915
Unit 10	n/a	n/a	316	1,094	316	1,094

Source	Base Year Emissions		Current Year Emissions		Increment Consuming Emissions[1]	
	24-hr[2] [lb/hr]	annual [TPY]	24-hr[3] [lb/hr]	annual [TPY]	24-hour [lb/hr]	annual [TPY]
Refineries						
Mandan[5]	2,372	10,391	1,210	5,298	(1,162)	(5,093)
Gas Processing Plants						
Grasslands	n/a	n/a	263	1,150	263	1,150
Little Knife	n/a	n/a	84	367	84	367
Tioga[6]	1,107	4,849	305	1,337	(802)	(3,512)
Lignite Gas	286	1,252	120	524	(166)	(728)
Dakota Gasification Plant						
Greatplain Synfuels	n/a	n/a	2,604	11,403	2,604	11,403
Sources that shut down after the baseline date						
Basin Electric Power Coop. - Neal Station					(297)	(1,302)
Montana-Dakota Utilities Co. - Beulah Station					(621)	(2,721)
Flying J Inc. - Williston Refinery					(45)	(198)
Royal Oak Briquetting Plant					(545)	(2,389)
TOTAL	**24,843**	**89,332**	**53,602**	**184,076**	**27,250**	**88,134**

[1] Negative numbers (i.e., in parentheses) indicate increment expanding emissions (i.e., current year emissions are lower than base year emissions).

[2] Annual numbers for the power plants are based on the Annual Emission Inventory Reports from 1976-1977 (e.g., *avg* S, annual coal use) and AP-42 emission factors. 24-hr numbers for the power plants are based on the ratio of the annual average emission rate (from 2000-2001 CEMS data) to the 90th percentile 24-hr emission rate (from 2000-2001 CEMS data) applied to the annual average emission rate in the base year.

[3] Numbers for the power plants are based on the 90th percentile of the 24-hr average from 2000 and 2001 CEMS data.

[4] Unit 2 had only been operating 9 months as of the minor source baseline date (12/19/77) and those 9 months were not considered representative of actual operation. Therefore, allowable emissions were used to determine baseline emissions. See 45 FR 52718, col 3, August 7, 1980.

[5] In a September 13, 2001 letter to the NDDH, BP indicated they could not locate an emission inventory for 1977. In that same letter, BP indicated that 1976 data would be representative of both 1976 and 1977.

[6] 1976 emission estimates are not available for the Tioga Gas Plant. Therefore, only 1977 emission estimates are used to determine baseline emissions.

Table 3-8

SO_2 INCREMENT INVENTORY FOR **MONTANA** CLASS I AREAS

Source	Base Year Emissions		Current Year Emissions		Increment Consuming Emissions[1]	
	24-hr[2] [lb/hr]	annual [TPY]	24-hr[3] [lb/hr]	annual [TPY]	24-hour [lb/hr]	annual [TPY]
Basin Electric Power Cooperative - Antelope Valley Station						
Units 1+2	n/a	n/a	3,440	12,557	3,440	12,557
Otter Tail - Coyote Station						
Unit 1	n/a	n/a	4,755	15,441	4,755	15,441
Great River Energy - Coal Creek Station						
Unit 1	n/a	n/a	4,269	14,462	4,269	14,462
Unit 2	n/a	n/a	3,429	12,213	3,429	12,213
PPL Corp. - Colstrip (Montana)						
Unit 3	n/a	n/a	655	2,868	655	2,868
Unit 4	n/a	n/a	597	2,615	597	2,615
CELP (Colstrip Energy Limited Partnership) (Montana)						
Boiler	n/a	n/a	420	1,839	420	1,839
Minnkota Power Cooperative - Milton R.Young Station						
Unit 1	4,208	14,176	6,087	20,585	1,879	6,409
Unit 2[4]	5,401	19,884	5,749	20,585	348	701
Basin Electric Power Cooperative - Leland Olds Station						
Unit 1	3,767	11,869	5,085	16,080	1,318	4,211
Unit 2	6,392	19,999	10,354	32,352	3,962	12,353
Montana Dakota Utilities Co. - Heskett Station						
Unit 1	578	1,734	342	1,026	(236)	(708)
Unit 2	1,512	3,895	849	2,189	(663)	(1,706)
Great River Energy - Stanton Station						
Unit 1	2,031	6,178	2,669	8,091	638	1,913
Unit 10	n/a	n/a	316	1,094	316	1,094

Source	Base Year Emissions		Current Year Emissions		Increment Consuming Emissions[1]	
	24-hr[2] [lb/hr]	annual [TPY]	24-hr[3] [lb/hr]	annual [TPY]	24-hour [lb/hr]	annual [TPY]
Refineries						
Mandan[5]	1,676	7,345	1,210	5,298	(466)	(2,047)
Gas Processing Plants						
Grasslands	n/a	n/a	263	1,150	263	1,150
Little Knife	n/a	n/a	84	367	84	367
Tioga[6]	1,107	4,849	305	1,337	(802)	(3,512)
Lignite Gas	490	2,147	120	524	(370)	(1,623)
Dakota Gasification Plant						
Greatplain Synfuels	n/a	n/a	2,604	11,403	2,604	11,403
Sources that shut down after the baseline date						
Basin Electric Power Coop. - Neal Station					(297)	(1,302)
Montana-Dakota Utilities Co. - Beulah Station					(621)	(2,721)
Flying J Inc. - Williston Refinery					(45)	(198)
Royal Oak Briquetting Plant					(545)	(2,389)
TOTAL	**27,162**	**92,076**	**53,602**	**184,076**	**24,931**	**85,390**

[1] Negative numbers (i.e., in parentheses) indicate increment expanding emissions (*i.e.*, current year emissions are lower than base year emissions).

[2] Annual numbers for the power plants are based on the Annual Emission Inventory Reports from 1977-1978 (e.g., *avg* S, annual coal use) and AP-42 emission factors. 24-hr numbers for the power plants are based on the ratio of the annual average emission rate (from 2000-2001 CEMS data) to the 90th percentile 24-hr emission rate (from 2000-2001 CEMS data) applied to the annual average emission rate in the base year.

[3] Numbers for the power plants are based on the 90th percentile of the 24-hr average from 2000 and 2001 CEMS data.

[4] Unit 2 had only been operating 9 months in 1977 and those 9 months were not considered representative of actual operation. Therefore, allowable emissions were used to determine 1977 emissions. See 45 FR 52718, col. 3. 1978 emissions are based on an emission limit of 1.2 lb_{SO2}/mmBtu for NSPS boilers (see 40 CFR Part 60 Subpart D) and an average heat content of 6427 Btu/lb_{coal}.

[5] In a September 13, 2001 letter to the NDDH, BP indicated they could not locate an emission inventory for 1977. In that same letter, BP indicated that 1976 data would be representative of both 1976 and 1977.

[6] 1976 emission estimates are not available for the Tioga Gas Plant. Therefore, only 1977 emission estimates are used to determine baseline emissions.

4. Results

The Calpuff modeling results are shown in Tables 4-1 through 4-6. To determine PSD compliance these modeled results are compared with the applicable Class I increments.

The PSD increments for SO_2 are specified in section 163(b) of the Act. For Class I areas, those increments are:

Annual arithmetic mean.....2 $\mu g/m^3$
Twenty-four hour average.....5 $\mu g/m^3$
Three hour average.....25 $\mu g/m^3$.

For any averaging period other than an annual averaging period, section 163(a) of the Act allows the increment to be exceeded during one such period per year. Otherwise, section 163 of the Act provides that the increments are not to be exceeded and that the State Implementation Plan must contain measures assuring that the increments will not be exceeded in the future. In the following tables, the number of exceedances indicates the number of times in each year that Calpuff predicted concentrations exceeding the applicable increment. Any number larger than one indicates a violation of the Class I increment.

Table 4-1. Calpuff Class I Increment Results
TRNP-South Unit
($\mu g/m^3$)

	1990	1991	1992	1993	1994
3-hr Predictions					
Highest	42.9	23.7	21.2	34.7	29.0
High, 2nd High	26.6	20.9	19.3	28.7	23.6
Max # of Exceedances	2	0	0	2	1
24-hr Predictions					
Highest	12.7	14.5	9.0	13.2	9.7
High, 2nd High	10.5	9.7	8.6	7.5	9.3
Max # of Exceedances	5	5	2	4	8

Table 4-2. Calpuff Class I Increment Results
TRNP-North Unit
(μg/m³)

	1990	1991	1992	1993	1994
3-hr Predictions					
Highest	23.2	32.7	33.5	33.4	20.4
High, 2nd High	20.2	29.1	29.6	30.3	18.1
Max # of Exceedances	0	4	2	2	0
24-hr Predictions					
Highest	8.9	14.6	8.5	9.0	6.8
High, 2nd High	8.1	11.0	6.3	7.5	5.5
Max # of Exceedances	4	6	4	5	2

Table 4-3. Calpuff Class I Increment Results
TRNP- Elkhorn Unit
(μg/m³)

	1990	1991	1992	1993	1994
3-hr Predictions					
Highest	12.7	19.9	15.3	27.1	16.7
High, 2nd High	12.1	19.9	14.5	21.8	16.3
Max # of Exceedances	0	0	0	1	0
24-hr Predictions					
Highest	2.2	4.7	2.8	3.7	4.4
High, 2nd High	2.0	3.9	2.7	3.2	2.8
Max # of Exceedances	0	0	0	0	0

Table 4-4. Calpuff Class I Increment Results
Lostwood Wilderness Area
(μg/m³)

	1990	1991	1992	1993	1994
3-hr Predictions					
Highest	23.3	28.0	20.3	22.5	20.6
High, 2nd High	14.7	23.6	18.9	18.2	20.4
Max # of Exceedances	0	1	0	0	0
24-hr Predictions					
Highest	5.9	9.1	9.2	6.5	5.5
High, 2nd High	5.6	8.3	5.3	5.5	5.4
Max # of Exceedances	2	10	4	4	3

Table 4-5. Calpuff Class 1 Increment Results
Medicine Lakes Wilderness Area
(μg/m³)

	1990	1991	1992	1993	1994
3-hr Predictions					
Highest	10.5	12.4	15.9	15.5	8.6
High, 2nd High	9.5	10.1	15.3	14.5	8.1
Max # of Exceedances	0	0	0	0	0
24-hr Predictions					
Highest	2.2	3.8	6.2	6.4	4.1
High, 2nd High	1.9	2.6	5.6	4.4	3.0
Max # of Exceedances	0	0	2	1	0

Table 4-6 Calpuff Class 1 Increment Results
Fort Peck Reservation
($\mu g/m^3$)

	1990	1991	1992	1993	1994
3-hr Predictions					
Highest	18.5	12.4	20.5	16.3	14.2
High, 2nd High	13.7	11.1	16.7	14.3	13.7
Max # of Exceedances	0	0	0	0	0
24-hr Predictions					
Highest	4.1	4.9	8.2	6.1	4.8
High, 2nd High	3.2	4.8	7.1	3.9	3.9
Max # of Exceedances	0	0	2	1	0

Table 4-7
Calpuff PSD Increment Analysis
Comparing Modeling Results Using Regulatory Defaults (bold) and Locally Developed Input Settings.

1990 Modeling Results	**TRNP South**	**TRNP North**	**TRNP Elkhorn R.**	**Lostwood Wilderness**
3-hr Predictions				
Highest	**57.1** /42.9	**29.1** /23.2	**14.3** /12.7	**27.4** /23.3
High, 2nd High	**46.8** /26.6	**26.2** /20.2	**14.2** /12.1	**25.6** /14.7
Max # of Exceedances	**11** /2	**3** /0	**0** /0	**2** /0
24-hr Predictions				
Highest	**21.9** /12.7	**16.4** /8.9	**4.0** /2.2	**11.6** /5.9
High, 2nd High	**20.4** /10.5	**9.7** /8.1	**3.1** /2.0	**8.4** /5.6
Max # of Exceedances	**5** /5	**6** /4	**0** /0	**10** /2

5. Summary of Results

In summary, EPA has applied the Calmet/Calpuff model to assess increment consumption in four Class I areas in North Dakota and eastern Montana. We based our analysis on long-standing EPA methodologies specified in our Guideline on Air Quality Models, the PSD regulations and other guidance. This includes the use of two years of actual emissions data and five years of historical meteorology data, including three years with enhanced MM5 meteorology data. We employed the locally developed inputs for the model used by the North Dakota Department of Health (NDDH) in their draft 1999 and 2002 analyses. The results of our analysis show numerous violations of the Class I PSD increments for SO_2 in all four Class I areas assessed. There were increment violations predicted in one or more Class 1 areas in every one of the five years of meteorology data modeled. The number of violations in each Class I area for the most adverse meteorological year in each area are summarized below:

Table 5-1
Summary of Class I Violations

	Theodore Roosevelt National Park, South Unit	*Theodore Roosevelt National Park, North Unit*	*Theodore Roosevelt National Park, Elkhorn Unit*	*Lostwood Wilderness Area*
3-hr Predictions 2nd High **# Violations**	28.7 µg/m^3 ('93) **1** ('93)	30.3 µg/m^3 ('93) **3** ('91)	<25 µg/m^3 **0**	<25 µg/m^3 **0**
24-hr Predictions 2nd High **# Violations**	10.5 µg/m^3 ('90) **7** ('94)	11.0 µg/m^3 **5**	< 5 µg/m^3 **0**	8.3 µg/m^3 ('91) **9** ('91)

	Medicine Lakes Wilderness Area	*Fort Peck Indian Reservation*	EPA's Class I SO2 Increments
3-hr Predictions 2nd High **# Violations**	< 25 µg/m^3 **0**	<25 µg/m^3 **0**	25 µg/m^3
24-hr Predictions 2nd High **# Violations**	5.6 µg/m^3 ('92) **1** ('92)	7.1 µg/m^3 ('92) **1** ('92)	5 µg/m^3

Note that, under EPA's PSD regulations, one exceedance of the short term (3-hour and 24-hour) increments is allowed per year, which is why this table identifies the modeled second high concentration.

The PSD permitting program and the State's Implementation Plan, or SIP, are the mechanisms intended by Congress for protecting the PSD increments. Specifically, section 161 of the Clean Air Act and 40 CFR 51.166(a)(1) provide that the SIP must contain emission limitations and such other measures as may be necessary to prevent significant deterioration of air quality. Section 163(a) of the Clean Air Act states that each SIP shall contain measures assuring that the maximum allowable increases (increments) over baseline concentrations shall not be exceeded. The court in *Alabama Power* made it clear that the PSD permitting program may not be sufficient to protect the PSD increments and that additional measures may need to be adopted into the SIP. (See *Alabama Power v. Costle*, 636 F.2d 323 at 362-3 (D.C. Circuit 1979.)

While facilities requesting a PSD permit to construct are required to perform increment-consumption analyses to determine whether the source would cause or contribute to a violation of the increment, EPA's regulations also require States to periodically review their plans for preventing significant deterioration. (See 40 CFR 51.166(a)(4).) If a State determines that an applicable increment is being violated, the State must revise the SIP to correct the violation as required by 40 CFR 51.166(a)(3). In addition, 40 CFR 51.166(a)(2) provides that, if a SIP revision would result in increased air quality deterioration over any baseline concentration, the SIP revision must include a demonstration that it will not cause or contribute to a violation of the applicable increments. Thus, there are several provisions of the Clean Air Act and EPA's regulations which require the protection of the PSD increments.